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Volume I — Drilling

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Drillstring vibrations:

what computer modelling and data analysis reveal

Failed measurement-while-drilling units, worn-out rock-bit bearings, fractured PDC-bit cutters, over-torqued connections and twisted-off connections are common examples of serious breakdowns caused by excessive impact loads or vibration-induced fatigue. Any such breakdown can result in lengthy roundtrips and the costly replacement of the failed part. By gaining an understanding of the dynamics of the drilling process, measures can be taken to reduce such harmful loading on the drillstring. Indeed, at KSEPL all three modes of vibration—lateral, longitudinal and torsional—have been investigated using theoretical analyses, computer simulations and high-quality field measurements. As a result, an effective active damping system for torsional vibrations has already been developed, and a promising strategy to tackle axial vibrations is being pursued.

Lateral vibration: whirl and chaotic motion

Lateral vibration is the least understood type of drillstring motion and probably the most difficult to control. Drilling with a slightly bent drill collar or with an unbalanced measurement-while-drilling (MWD) unit can result in violent side-to-side movements (Figure 1a) analogous to the whirling motion of an out-of-balance centrifuge. Friction generated between the stabilisers or bottomhole assembly (BHA) and the borehole wall can produce a similar motion but in the opposite direction: backward whirl, or precession (Figure 1b). A third mode of lateral motion is a more or less irregular bouncing of the drill

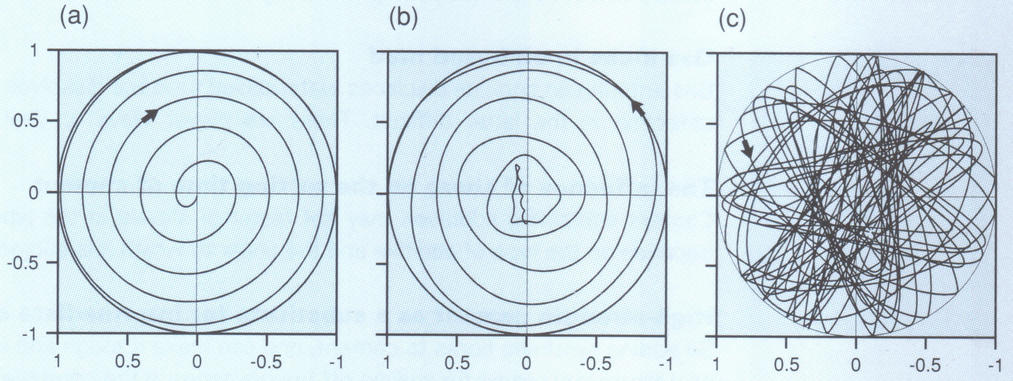


Figure 1

Computer simulations of the forward whirl *(a)*, backward whirl *(b)* and strongly irregular motion *(c)* of a stabilised span of drill collars.

The spiralling curves represent the trajectory of the collar axis as traced out on a plane midway between the stabilisers, looking into the hole. A displacement of unity indicates contact between the collars and the borehole wall.

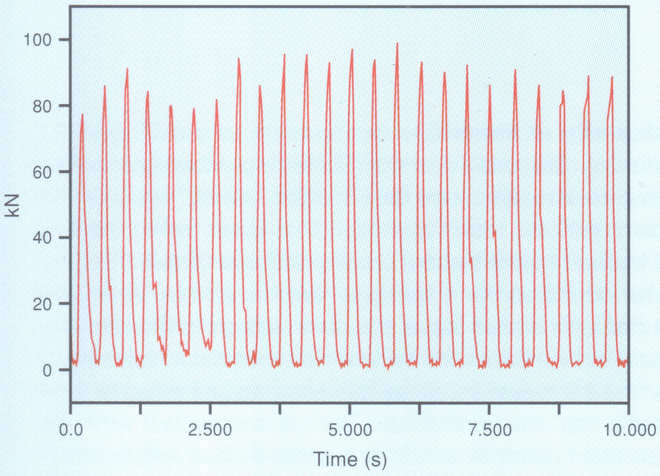


Figure 2

Bit bounce as seen in measurements of dynamic downhole weight-on-bit while a 9 $^{7}/_{8}$″ fishtail bit is run in.

collars against the borehole wall (Figure 1c). This behaviour sometimes becomes completely chaotic.

Longitudinal vibration: bit bounce

Large longitudinal vibrations, or "bit bounce," is a common drilling phenomenon. This up-and-down motion imparts heavy axial loads on the drillstring, particularly on the drill bit (Figure 2). The way in which various factors affect bit bounce is not yet entirely known, therefore theoretical predictions of resonance speeds (critical rotary speeds) are of limited value. Nevertheless, analyses of measurements of drillstring dynamics indicate that a positive displacement motor can help to prevent bit bounce. Another solution is offered through the proper selection and implementation of shock subs: telescopic BHA components that modify the resonance frequency of the drillstring. The most recent weapon against axial drillstring vibration is a hydraulic telescopic BHA component that effectively separates the motion of the bit from the motion of the drillstring. Until now, the application of such thruster tools has been restricted to slim-hole drilling operations, but plans to adapt them for use in larger holes look promising.

A potentially even better solution to combat bit bounce is real-time monitoring of downhole vibrations with the aid of surface measurements. This form of direct feedback will enable the driller to react to severe vibrations by changing operating parameters, such as rotary speed or weight-on-bit, and to immediately observe the effect of the corrective action. Tests with this type of vibration control will start at the beginning of 1991.

Torsional vibration: stick-slip

Stick-slip is the fluctuating rotary speed at the bit caused by the bit becoming stuck in the formation long enough for the drillstring to torque up, or become twisted. When the bit then comes loose, it whips around at very high speed (Figure 3), much like an uncoiling spring. This friction-induced vibration is self-excited (as is the squealing of car brakes) but is more likely to occur at a low rotary speed and a high weight-on-bit. The periodic torqueing up of the drillstring is easily monitored at the surface through the varying motor current. Indeed, such monitoring has been applied to control the stick-slip motion in the soft-torque rotary table (see "The soft-torque rotary table," pp. 4-5)

Secondary effects of vibrations

Although the primary effect of these three types of drillstring vibration is to increase the mechanical loading on drillstring components, research into the subject has revealed many secondary effects that are also detrimental to the drilling process. Longitudinal vibration, for example, means that the bit makes contact with the bottom of the hole only intermittently, resulting in a completely different cutting mechanism that lowers the bit's overall rate of penetration. Additionally, torsional vibration is responsible for a strong periodic interaction between the mud in the wellbore and the rotating drillstring. The interaction creates pressure pulses of over 200 psi in the mud system. These pulses not only affect wellbore stability but also have been observed to swamp weaker MWD signals, making it impossible to decode the signals at the surface.

As KSEPL achieves a more complete understanding of such drillstring vibrations, methods can ultimately be devised to achieve smoother and more efficient drilling operations and to avoid the loss of time associated with the failure of drillstring components.

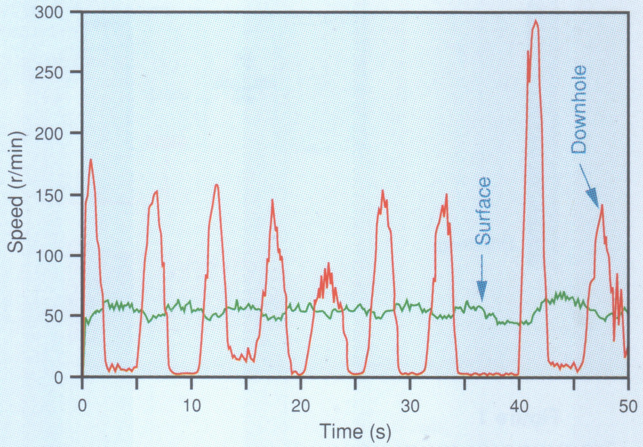


Figure 3

Drillstring rotary speed, measured both downhole and at the surface, showing severe stick-slip.

The soft-torque rotary table

As a step to alleviate the problems caused by drillstring vibration, KSEPL has developed an active damping system for attenuating torsional oscillations of the drillstring. It thus prevents the build up of energy in torsional waves that are reflected back and forth between the bit and the rotary table. The system, which relies on a minor modification to the speed control system of the rotary table, is cheap to implement and has already been successfully operated in the field.

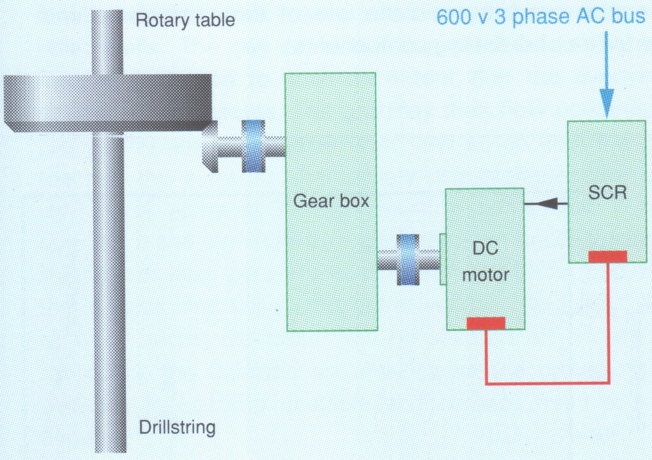


Figure 1

THE SOFT-TORQUE ROTARY DRIVE.

The current signal of the DC motor, which varies as the torque on the rotary table, is used to regulate the speed of the rotary table. (Note that this system is not a constant-speed control.) The system enables torsional waves travelling up the drillpipe to be absorbed by the rotary table.

Stick-slip at the bit

Stick-slip (as explained in "Drillstring vibrations: what computer modelling and data analysis reveal," pp. 2-3) is a violent periodic torsional motion that arises when the drill bit stalls in the formation, causing the rest of the drillstring to be wound up like a spring by the rotary table. When the bit suddenly comes loose, the strain energy in the torqued-up drillstring causes the bit to whip around at a high speed. As the bit does so, it generates a torsional wave that travels up the drillstring. The rotary table, with its associated gear-box and motor, generally has a high inertia and acts like a fixed end to the drillstring, and therefore it reflects the torsional wave back down the drillstring. When the reflected wave reaches the bit, the torsional-wave cycle begins anew. This behaviour of the drillstring results in a periodic variation in the kelly torque required. In fact, the effect of the varying load on the rotary drive is clearly audible on the drilling rig as periodic fluctuations in the noise from the drive mechanism.

Catching the torsional wave

To prevent damage to downhole components from such periodic vibrations, the flow of energy up and down the drillstring has to be interrupted. A convenient way to do so is to remove the reflections at the rotary table. Research showed that this can easily be achieved through a small modification of the control system of the DC motor driving the rotary table. Since the motor's current is a measure of the torque at the rotary table, it can be used to control the motor's rotary speed. In this way the dynamic character of the rotary table can be changed completely: the rotary table can be made to react like a "soft" top end instead of like a "fixed" heavy flywheel. As a result, the torsional waves arriving at the rotary table are completely absorbed, and the vicious circle of torsional drillstring vibration is broken. Although small fluctuations in bit speed may still result in weak torsional waves travelling up the drillstring, they are no longer reflected from the surface. Hence, the waves' amplitudes do not build up, and the development of stick-slip vibration is prevented.

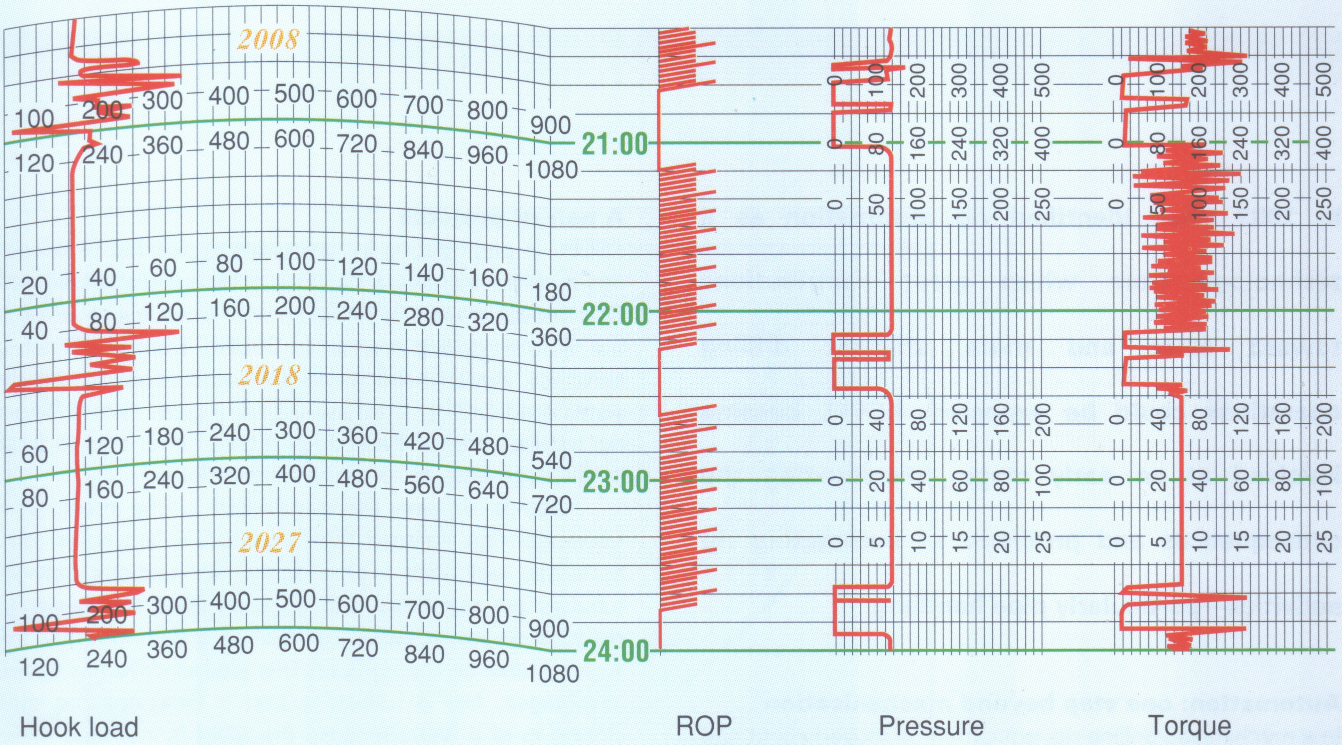


Figure 2

Geolograph recording showing the effectiveness of the soft-torque rotary table.

Between 2,008 and 2,018 metres the soft-torque control system was switched off. As can be seen, the torque on the rotary drive during that drilling interval fluctuated considerably. From 2,018 to 2,027 metres the control sytem was active, and the torque fluctuations disappeared.

Implementation and field trials

The modified, "soft-torque" rotary table was first implemented on rigs equipped with electronically controlled drives, since the electric motor of that particular drive was the easiest to control (Figure 1). Most existing rotary drives, however, can be outfitted with a similar control system at a very low cost (of the order of a few hundreds of dollars). The system can also be installed into electrical top drives.

So far, the soft-torque rotary table has been applied by only a few Operating Companies—but with great success. Figure 2 shows the Geolograph reading taken from a rig equipped with such a rotary table. The rig was running with the control system switched on for every other single. Between 2,008 and 2,018 metres the table's control system was switched off. As can be seen on the reading, high torque variations were experienced during the entire interval. When the control system was switched on for the next single, the torque variations disappeared. In view of such results, steps are being taken to make the soft-torque rotary table available to all other Operating Companies.

An automated drilling rig

In 1983 Shell identified rig automation as a technology from which great contributions toward safer and more efficient drilling operations could be expected. KSEPL became involved at an early stage, investigating the consequences and problems of automating rig activities—particularly pipe handling.

Automation: one step beyond mechanisation

In a mechanised drilling rig, equipment is moved about and manipulated by manually controlled machines. In an automated drilling rig, however, that controlling task is taken over by a computer. The technology required for automation is considerably more sophisticated than that for mechanisation. The information necessary to control an operation has to be supplied by many types of sensors. An additional challenge is that the control system and the sensors have to function reliably under extreme conditions.

Activities suitable for automation

Right from the start it was clear that pipe handling would be one of the activities most suitable for automation on a drilling rig. It constitutes a large part of the work on the rig, and it is potentially dangerous (about half of all accidents on a rig are related to pipe handling). Moreover, it is relatively easy to put under computer control. To take full advantage of the potential crew reduction offered by automation, however, other rig activities will have to be computer-controlled as well. Automated systems could be used to great advantage, for example, in the handling of mud, cementing and the blowout preventer.

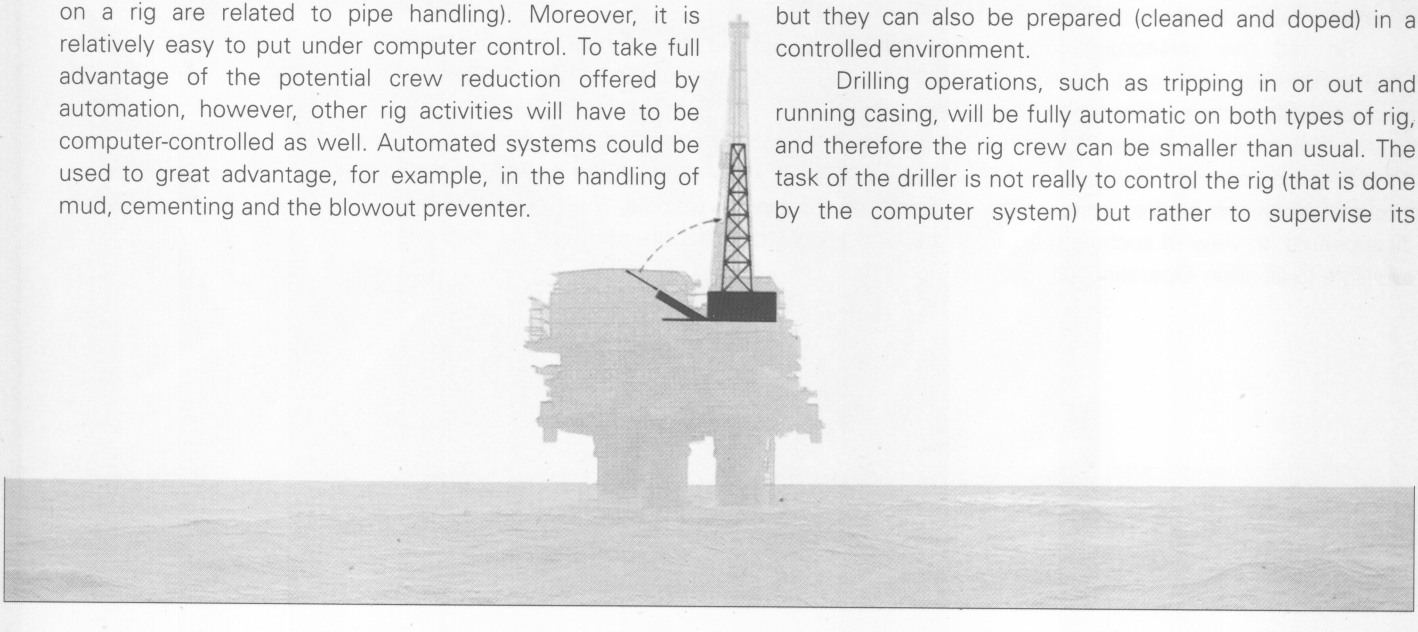
A pair of projects

KSEPL is participating in two projects seeking to develop rigs in which all manual handling of pipe is dispensed with. One project arose in connection with a request received by the German drilling contractor, Deutag, from the Dutch oil company, Nederlandse Aardolie Maatschappij. The Deutag Automated Drilling Machine (ADM) (Figure 1) is a singles rig: tubulars are handled one at a time rather than in three-length segments, as is conventionally done.

Stands of pipe are not racked in the mast, as in traditional rigs. Instead, each tubular is laid down on a horizontal rack with a pipe boom. Connections between tubulars are made up with an automated torque-wrench machine. A power swivel rotates the drillstring rather than a rotary table on the rig floor. This type of drive has several advantages, one of which is that it facilitates the quick closing in of a well. Because the ADM is intended mainly for onshore use, its transportability has been a key design point.

The other project, known as the Rig Automation-Drilling (RA-D) project, is sponsored by a number of oil companies including Shell (Expro). The automated rig in this case is being built by the British engineering firm, Strachan and Henshaw (S&H). Although the RA-D rig is based on the same concept as the ADM rig, it is intended primarily for offshore drilling and so does not have to be designed to be transported every three or four months. A striking feature of the RA-D rig is the logistics of the tubulars. All tubulars, including drillpipe, drillcollars, casing and stabilisers, are stored on pallets called "strongbacks". Not only are the tubulars easier to manipulate in this way, but they can also be prepared (cleaned and doped) in a controlled environment.

Drilling operations, such as tripping in or out and running casing, will be fully automatic on both types of rig, and therefore the rig crew can be smaller than usual. The task of the driller is not really to control the rig (that is done by the computer system) but rather to supervise its



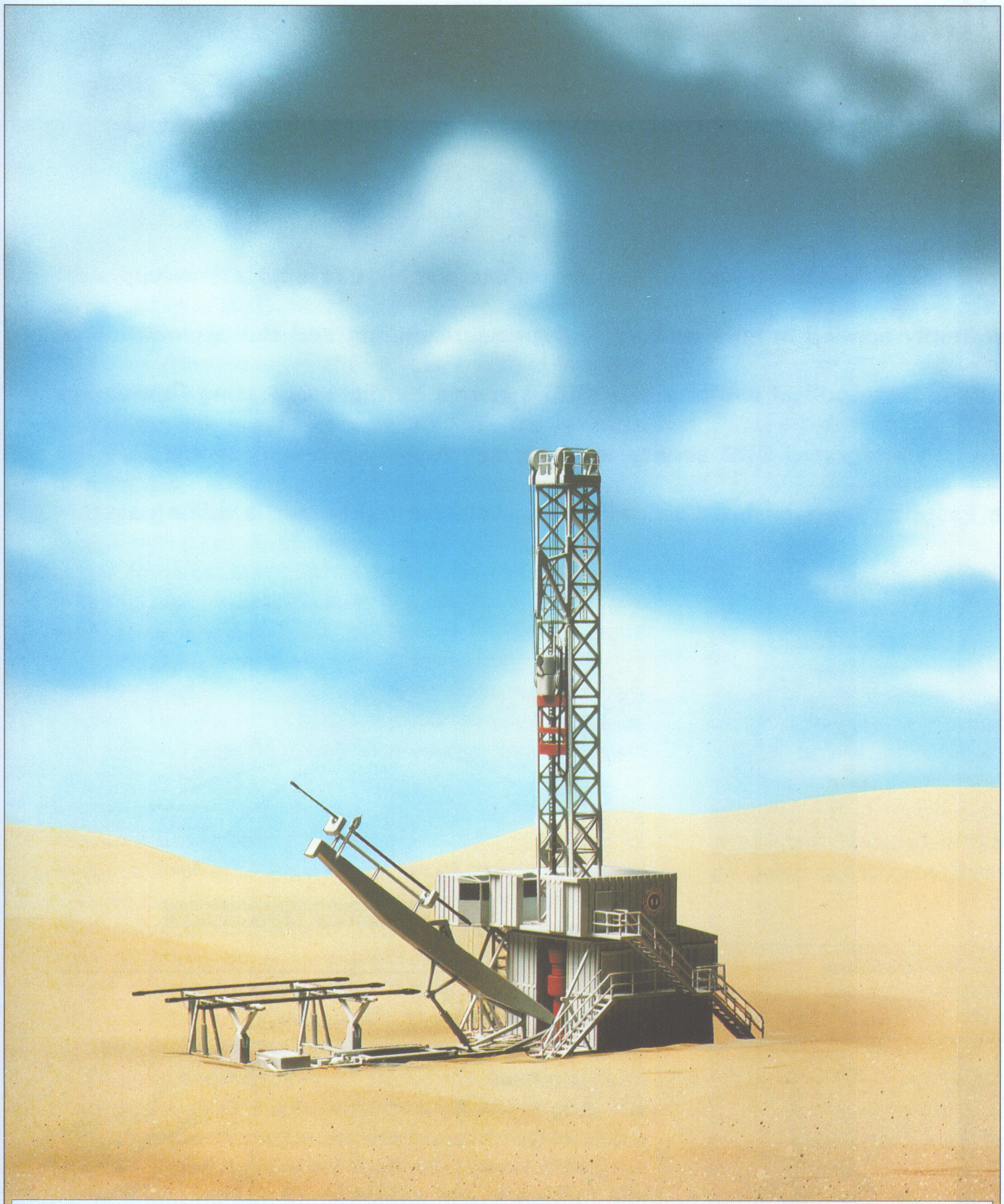


Figure 1
Model of Deutag automated drilling machine (ADM).

operation. At any time, however, the driller can assume control, which will probably be necessary whenever an unusual situation arises.

At Shell's request, Thule Rigtech has investigated the possibility of automating the mud and cementing systems. The goals of this project were to develop a compact, lightweight and simplified system that enables all standard storing, mixing, solids removal tasks to be performed and controlled entirely by machine.

The future

Both Deutag and S&H plan to start building the first prototypes of their automated rigs in 1990, so that by the end of 1991 both rigs should be ready for testing. The results of the design study on the mud and cementing systems became available in mid 1990. The experience gained in these projects will no doubt become the basis on which to develop the next generation of automated rig.

Slim-hole drilling:

well cost reductions of 15-40% already achieved, more expected

Slim-hole drilling (SHD) offers considerable opportunities to reduce the cost of exploration/appraisal wells. It could also be profitably applied in infill drilling, high-pressure drilling and the exploitation of deep, tight gas reservoirs. The first applications of partial SHD systems by three Operating Companies have yielded large savings. An integrated SHD service is being developed on behalf of KSEPL/SIRM under an agreement with Eastman Christensen. Shell will have exclusive rights to the drilling system until the end of 1996.

Cheaper, greener drilling

Slim-hole drilling (SHD) encompasses the array of technologies that enables wells with a diameter smaller than 6 1/4" to be drilled and completed more efficiently. The difference between a conventional casing scheme and two SHD alternatives are illustrated in Figure 1. The narrower holes have resulted in savings of between 15 and 40 per cent as a result of the concomitant reductions in casing, rig size, location area, mud, cement and transport. Less waste mud and cuttings, which are sources of pollution, are generated as well.

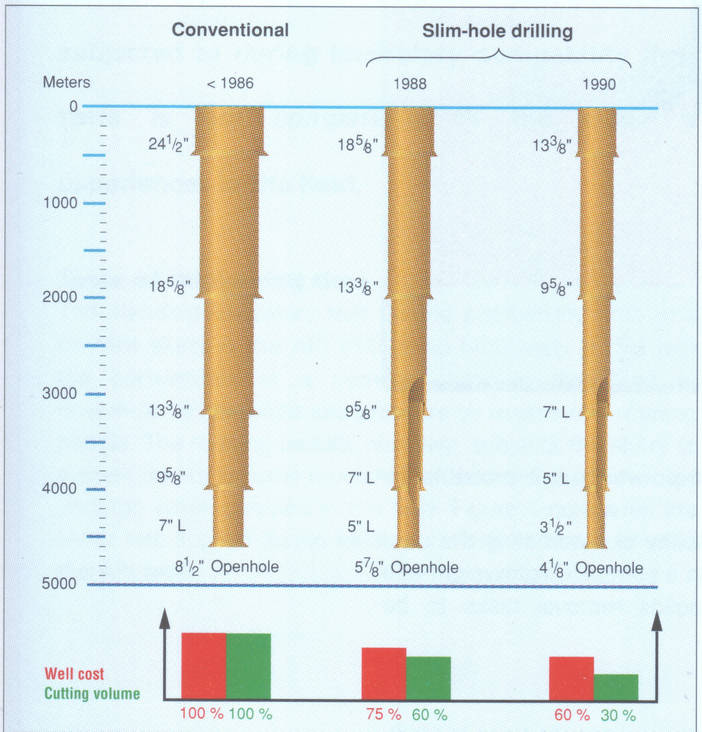


Figure 1

CONVENTIONAL CASING SCHEME COMPARED WITH TWO SLIM-HOLE DRILLING (SHD) ALTERNATIVES.

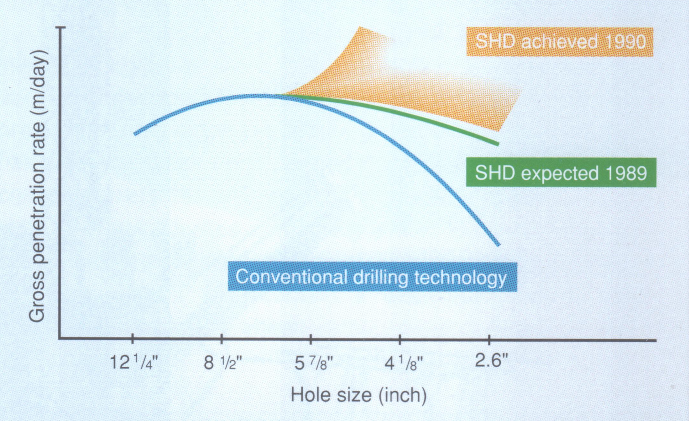


Figure 2

EXPECTED AND ACTUAL RESULTS OF INITIAL SHD TRIALS.

The wide scope of narrow holes

The SHD project was initiated by the SIPM Drilling Spearhead as a technique to drill low-cost vertical exploration wells on land. The results of the first applications of some partly developed systems were better than expected (Figure 2). Indeed, the results were so encouraging that Shell Research is considering a possible application of SHD for deep, high-pressure wells, with the first field trials expected during 1991. The first phase of the SHD project, however, includes the development of "retrofit" equipment, which can be employed on nearly all land and jackup rigs (Figure 3).

Traditionally, well sizes have been determined by drilling requirements rather than production requirements.

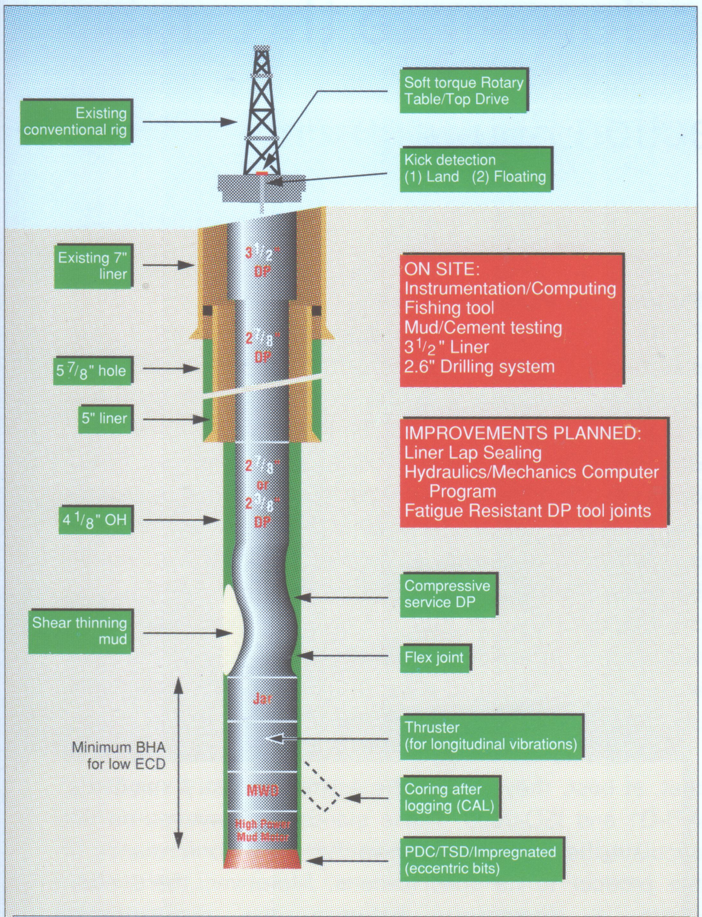

Existing conventional rig
Soft torque Rotary Table/Top Drive
Kick detection (1) Land (2) Floating
Existing 7" liner
3 1/2 DP
ON SITE:
Instrumentation/Computing
Fishing tool
Mud/Cement testing
3 1/2" Liner
2.6" Drilling system
2 7/8 DP
5 7/8" hole
5" liner
IMPROVEMENTS PLANNED:
Liner Lap Sealing
Hydraulics/Mechanics Computer Program
Fatigue Resistant DP tool joints
2 7/8 or 2 3/8 DP
4 1/8" OH
Compressive service DP
Shear thinning mud
Flex joint
Jar
Thruster (for longitudinal vibrations)
Minimum BHA for low ECD
MWD
Coring after logging (CAL)
High Power Mud Motor
PDC/TSD/Impregnated (eccentric bits)

Figure 3
Equipment for the "retrofit" SHD system.

However, new developments in completion techniques (e.g., coiled tubing, selective placement tools and wireline-set bridge plugs) have made the monobore completion concept (Figure 4), developed by Shell Expro, a key element of the SHD project.

Integrated application of an evolving technology

SHD is made technically possible by the combination of KSEPL's fundamental understanding of drilling and completion processes (as evinced by the other articles in this issue), the expertise of the Shell Operating Companies in carrying out the processes, and the practical knowledge of Eastman Christensen in developing the necessary tools and techniques. The success of the initial applications of the partial SHD systems has given the project momentum, but it is now gaining added impetus from the practical demands of Operating Companies.

BEB, a German company owned by Shell/Esso, is now routinely drilling $4^1/_8$" holes for exploration and production wells, with a $2^5/_8$" contingency hole size. Production rates from tight, deep sandstones through $3^1/_2$" liner are comparable to conventional wells (with 7" production casing). Indeed, a production sidetrack with a diameter of $2^5/_8$" and a length of 107 m at a depth of 4000m is now producing at the same rate as the original well.

Petroleum Development Oman, has reduced hole sizes of some exploration/appraisal wells from $17^1/_2$" x $12^1/_4$" to $8^1/_2$" x $6^1/_8$". Costs savings amounting to as much as 27% have been reported. Further gains are anticipated as soon as a dedicated, small SHD rig is introduced. Drillstring vibrations were often experienced in this hard-rock area, but SHD operations have proved to be trouble free. In fact, the rate of penetration (ROP) was doubled in some instances, and the number of twist-offs was reduced.

A reduction in bit and drillstring vibrations was also in large part responsible for the improved drilling performance noted by the Nederlandse Aardolie Maatschappij when drilling a $5^7/_8$" hole using SHD technology. Compared to offset wells, the SHD well exhibited double the ROP, considerably longer bit runs and a reduction in trouble time.

The future

Shell Expro and the Shell Petroleum Development Company of Nigeria are considering drilling SHD exploration/appraisal wells into deep, high-pressure, high-temperature prospects. Shell Expro intends to conduct the operations from floating drilling vessels, and this calls for new concepts for heave compensation and kick detection. In addition, plans are already being discussed for a light land rig (perhaps even transportable by helicopter) capable of reaching depths of 4,000 to 5,000 m. Such a rig will reduce the costs and environmental impact of drilling even further.

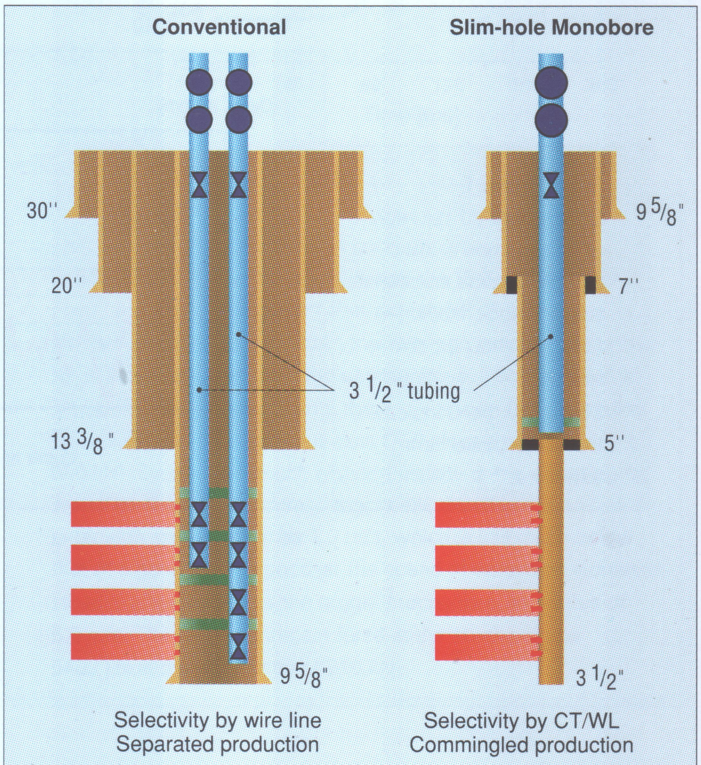


Figure 4
Monobore concept for SHD-based completions.

More consistent PDC bit performance through SQAIR: Shell Quality And Inspection Requirements

Although polycrystalline-diamond-compact (PDC) drill bits (photograph on p. 13) can perform excellently, field experience has shown variable performance. One reason for this inconsistency is inadequate quality control during manufacturing. A list of specifications—the Shell Quality and Inspection Requirements (SQAIR)—was therefore developed for PDC bits. By purchasing a PDC bit according to the SQAIR, one can be confident that the bit has passed a stated level of quality control that is independent of the bit manufacturer.

Reason for PDC-bit SQAIR

Field-run evaluations, complemented by laboratory measurements (Figure 1) and computer simulations (Figure 2) at KSEPL, indicated that the position of the individual cutters on polycrystalline-diamond-compact (PDC) bits can deviate significantly from their design position. These deviations degrade the bit's performance and reduce its overall service life. Unfortunately, the brunt of the costs entailed by drilling with an inferior PDC bit is ultimately borne by Shell rather than the bit manufacturer. For a bit manufacturer, a premature bit failure means that, in the worst case, it has to replace the bit. For Shell, however, such a bit failure can mean costly remedial operations, such as round trips, fishing jobs, sidetracks or worse.

Visits to the major PDC-bit manufacturers revealed that, at best, they rely on the existing industry standards, API-Q1 and ISO-9000. These standards, however, do not stipulate the procedures for verifying the conformance of the product to its specifications. Moreover, there often exists a discrepancy between the quality-control procedures that are actually followed and those laid down. These facts justified drawing up a quality and inspection document.

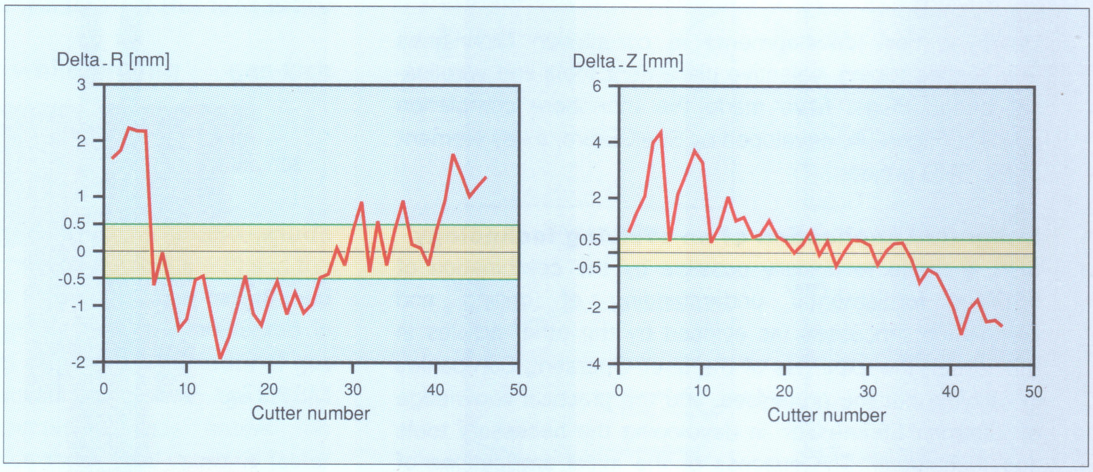


Figure 1
Deviation of cutter from design position in axial direction along bit centre line (*a*) and in radial direction from bit centre line (*b*).
The yellow band indicates the actual placement tolerance.

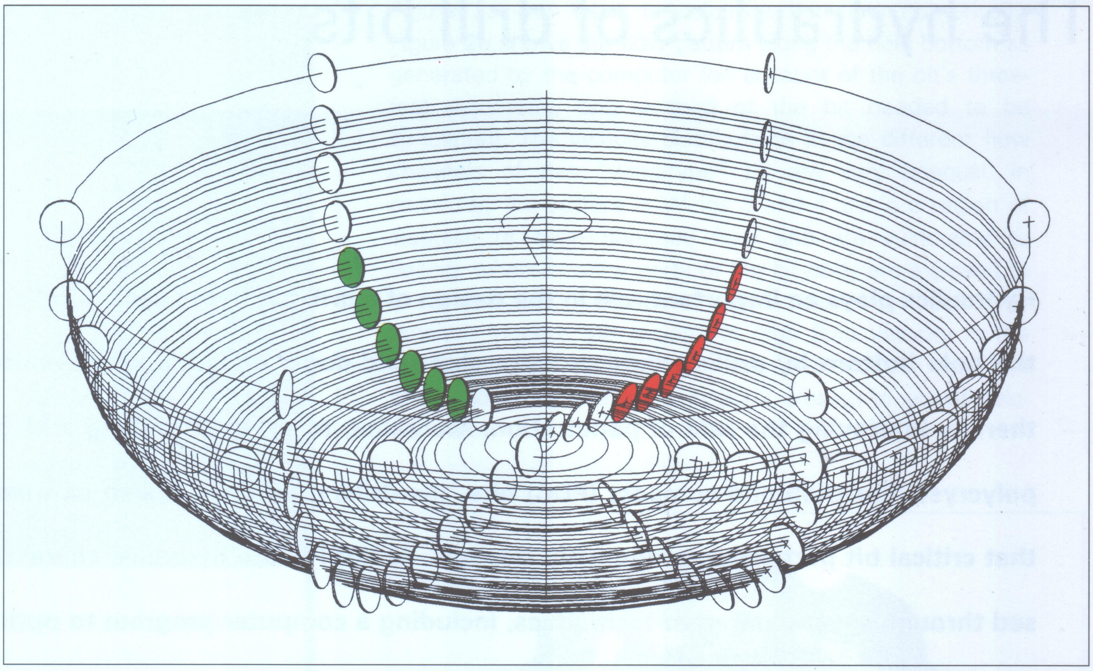


Figure 2

THREE-DIMENSIONAL CUTTER DISTRIBUTION AND TRAJECTORIES AS SIMULATED ON A COMPUTER.

As shown in Figure 3, the areas cut by the red and green cutters differ substantially.

Contents of PDC-bit SQAIR

In particular, the SQAIR defines certain inspection techniques, sampling frequencies and acceptance criteria for PDC bits. Two SQAIRs have been formulated, one for steel-body bits and one for matrix-body bits. The documents deal with such issues as:

- the origins and metallurgical details of materials used
- the quality of welds and bonds
- the infiltration testing, tap density and sieve analysis of matrix powders
- the cutter placement measurement
- the cutting-force calculation (see Figure 3)

The SQAIRs do not specify the manufacturing procedure, nor do they place any constraints on the bit design. *The objective is to ensure that the quality standards applied by the bit manufacturers result in satisfactory PDC-bit performance.*

Benefits of PDC-bit SQAIRs

The SQAIRs for PDC bits provide:

- a way to ensure a consistent quality among purchased PDC bits
- clear specifications to simplify procurement
- increased standardisation
- a basis for price comparison

Date of issue

A draft of the PDC-bit SQAIRs will be sent to bit manufacturers at the end of 1990 to serve as guidelines for upgrading their quality-control procedures. Given the state of existing procedures, it will take them at least six months to satisfy the SQAIR specifications fully—especially the specifications concerning cutter-placement measurement and cutting-force calculation. The PDC-bit SQAIRs are therefore not expected to go fully into effect until the second half of 1991.

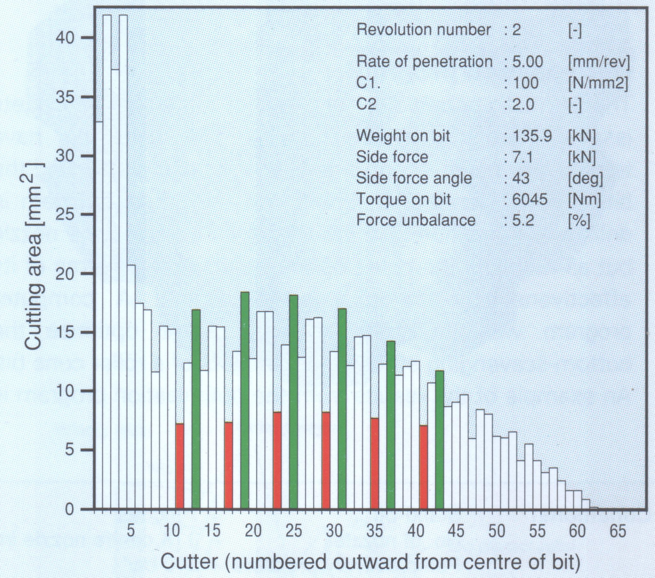


Figure 3

RESULTS OF A CUTTING-FORCE CALCULATION.

The differences in cutting area between the red and green cutters of Figure 2 results in a non-uniform wear distribution.

The hydraulics of drill bits

Hydraulics plays an important role in the design of a drill bit. In the case of roller cone bits, scavenging of the hole bottom by drilling fluid reduces chip hold-down effects and prevents re-grinding of cuttings, thereby improving the rate of penetration. Moreover, to avoid bit balling with both roller cone bits and polycrystalline-diamond-compact (PDC) bits, the drilling fluid must also be made to flow in such a way that critical bit parts are continuously cleaned. At KSEPL, the hydraulic characteristics of bits are assessed through several different techniques, including a computer program to optimise bottomhole erosion and improve crossflow, flow-visualisation experiments to ascertain the flow patterns around roller cone bits, and numerical flow simulations to evaluate the flow patterns in common PDC bit configurations.

Optimisation program

The hydraulic horsepower and impact force of the fluid jets issuing from the nozzles of a roller cone bit have traditionally been recognised as major factors affecting the bit's rate of penetration (ROP). Yet the critical concern in drilling is the action of the fluid not as it leaves the nozzle but as it strikes the hole bottom, particularly in terms of its effectiveness in bottomhole scavenging. A computer program was therefore written to help optimise the bottom-scavenging efficiency of the jets of a roller cone bit. An example of the results from the optimisation program is shown in Table 1. On the basis of numerous such results, the following conclusions could be drawn:

- Extended nozzles provide greater bottomhole erosion directly under the nozzles (i.e., around the gauge) than nozzles with a conventional stand-off.
- Impact force provides a better indicator of bottom hole cleaning than hydraulic horsepower.
- Considerable benefits are obtained by blanking off a nozzle (either extended or conventional), provided the total flow area is adjusted to maximise the impact force.

Conditions:

Stand-off = 7 inches
No. of nozzles = 3 (& centre nozzle in the second case)
Pump delivery pressure = 210 bar
Well depth = 2500 metres
Mud properties YP = 16 lbf/100 sqft, PV = 20 cP, density = 1120 kg/m^3

Optimising criterion	Without centre nozzle			With centre nozzle (size 14)		
	Flow rate (l/min)	Nozzles	Relative bottomhole erosion	Flow rate (l/min)	Nozzles	Relative bottomhole erosion
HORSEPOWER/IN^2	2379	14-13-13	1.00	2385	11-11-10	0.35
IMPACT FORCE	2949	16-16-16	1.63	2975	14-14-14	0.64
BOTTOMHOLE CLEANING						
All nozzles	2949	16-16-16	1.63	3361	16-16-18	0.81
One nozzle blanked	3007	20-20-0	2.35	3084	18-18-0	1.34

Table 1

Hydraulics optimisation of a $12^{1}/_{4}$" bit with conventional nozzles.

The relative bottomhole erosion parameter is only for ranking purposes; it is not a prediction of the rate of penetration.

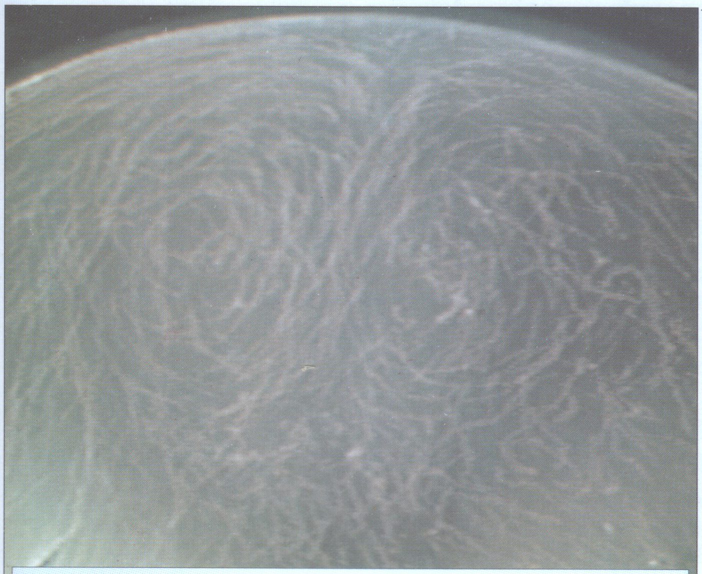


Figure 1

Laser-sheet visualisation of flow around roller cone bit with one blanked-off nozzle.

The trajectories of the illuminated particles trace out a pair of counter-rotating vortices at the blanked-off side.

Flow visualisation of roller cone bits

Although the KSEPL computer program has proved successful, it does not really describe the way jet flows interact with one another and how they are affected by the geometry of the bit/hole system. The actual flow pattern below a roller cone bit was therefore investigated by shining laser light on particles entrained in clear fluid as it was pumped through a full-scale mock-up of a $17^1/_2$" bit in a borehole (Figure 1). These experiments revealed the following features:

- A centre nozzle increases the fluid turbulence around the cones, which is the main mechanism for cone cleaning. There is a danger of severe bit erosion, however, if any part of the cones or teeth is less than six nozzle diameters away from the nozzle.
- The fluid flow over the cones caused by the outer jets is also important for cone cleaning. Outer nozzles should therefore not be blanked in soft formations nor in holes that are shallow or larger than $12^1/_4$"
- With three open outer nozzles, the flow at the centre of the hole is not only very sluggish (less than 10% of that at the gauge) but also rotational and unsteady. Blanking a nozzle increases the crossflow at the centre of the hole, but not as much as the overall increase due to larger nozzles.

Numerical simulations of PDC bit hydraulics

The difficulty of accurately measuring the flow field around polycrystalline-diamond-compact (PDC) bits—or, for that matter, of calculating the flow field analytically—has compelled investigators to resort to numerical techniques to solve the fluid flow equations. At KSEPL, for example, a computer model of the Hycalog SX 39B $12^1/_4$" bit shown in Figure 2a was used to calculate the flow numerically. Figure 2b shows the flow pattern along the hole bottom as generated by the computer (on account of the bit's three-fold symmetry, only a third of the bit needed to be simulated). The velocity distributions in the different flow channels of this "wing-type" bit are very unequal. In particular, the cutters in Wings 3 and 4 are in a region of sluggish or even reversed flow and are vulnerable to balling, whereas other parts of the bit body are exposed to excessive flow velocities, which result in local body erosion. Indeed, the regions of high fluid velocity in the numerical flow simulation correspond closely with the areas exhibiting the greatest body erosion in actual field-worn bits.

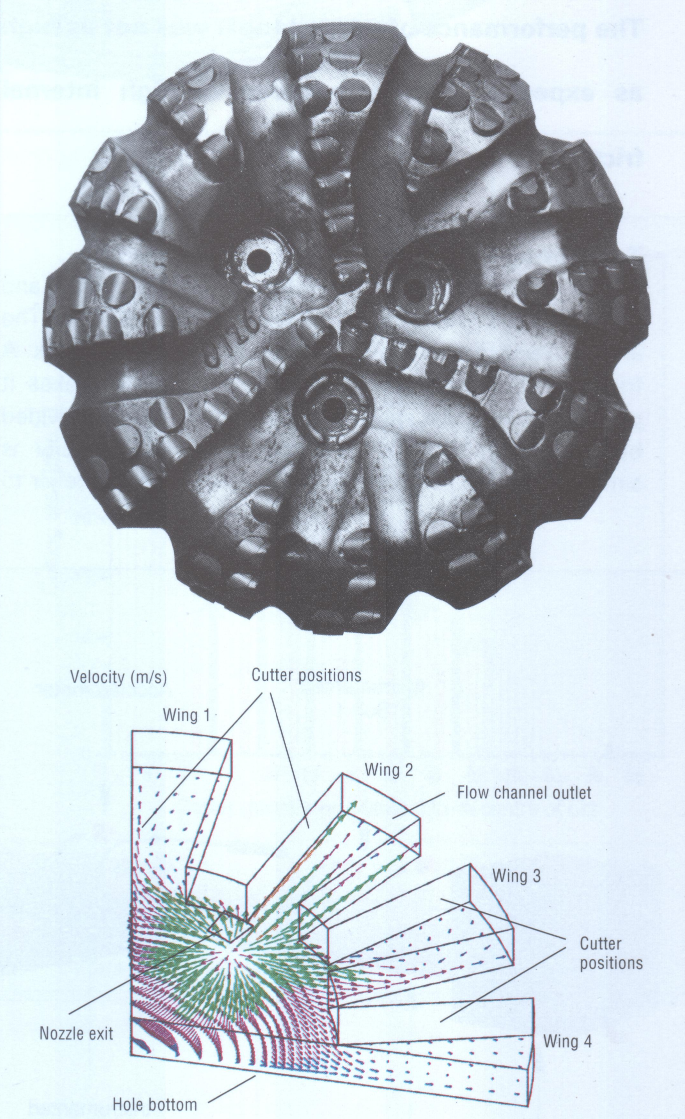


Figure 2

The Hycalog SX39B PDC bit (*a*) and the computed velocity vectors along the hole bottom with nozzle exit velocity= 140 m/s (*b*).

The performance of jars and accelerators

Twenty one jars and ten accelerators were evaluated as part of a test programme sponsored by Norske Shell and Statoil, supervised by KSEPL, and carried out by Rogalandsforskning. The performance of several tools was not as high as expected, mainly because of high internal friction.

Test set-up

The test rig (shown in Figures 1 and 2) is 75 m long and can withstand impact loads of more than 7 000 kN. The anchor foundation is a heavy rock-bolted concrete block. A friction collar, which simulates the stuck point, makes it possible to vary the sticking force. The jar pull is provided by a hydraulic cylinder, and the drillstring elasticity is simulated with a jar accelerator. A swivel enables the jar to be "cocked". Forces are recorded by instrumented subs, and any movement of the jar and accelerator is measured with linear-displacement transducers.

Test results

The test results for a bad and a good jar are shown side by side in Figure 3. The high internal friction (395 kN) of the bad jar causes the pull to decrease right after the release of the trigger, decelerating the extension. As a result, the jar impact force is even less than the static pull before the release. The internal friction of the good jar, in contrast, is only 42 kN, and the extension shows a steady acceleration until the point of impact.

Accelerators also were susceptible to high internal friction, leading to a loss of the energy that would otherwise be available for accelerating the jar extension and enhancing the jar impact. Although every accelerator will boost the jarring impact to some extent, the accelerators' contribution would have been much higher had they been designed better.

Indeed, most jars and accelerators tested exhibited excessive dynamic friction, which obviously had an adverse effect on their impact force. Only four of the 21 jars and

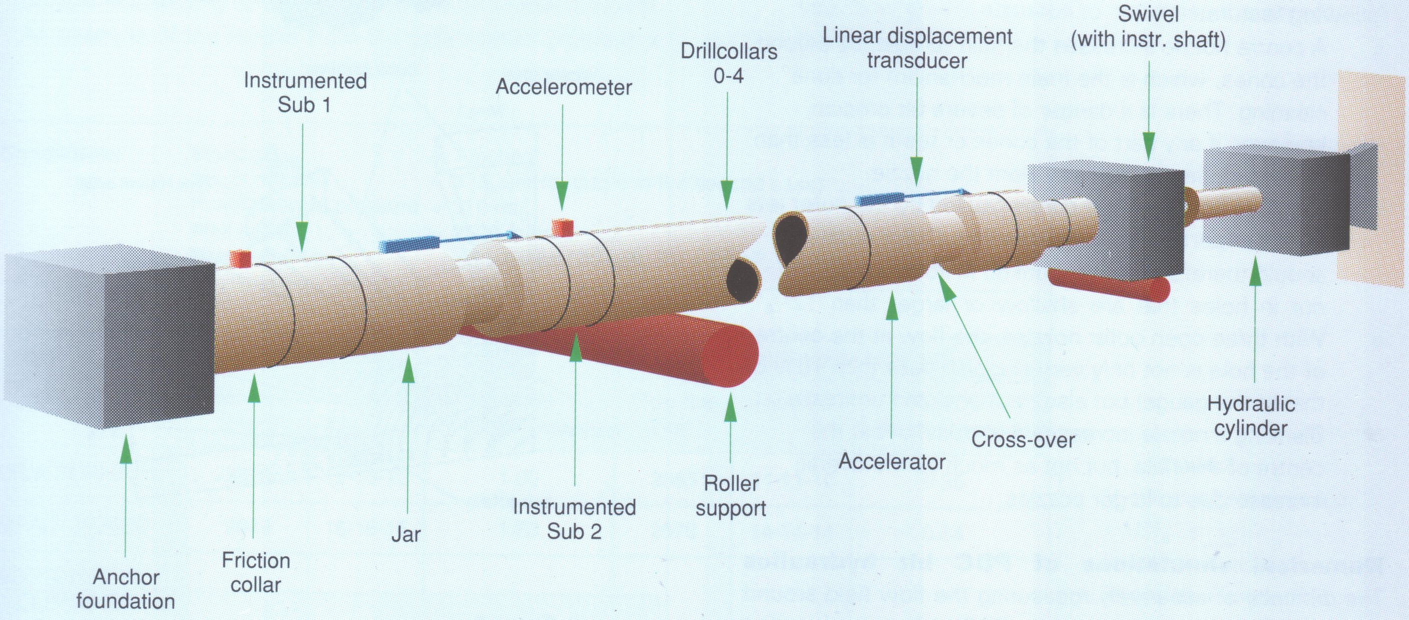


Figure 1

JARRING TEST ASSEMBLY AND INSTRUMENTATION.

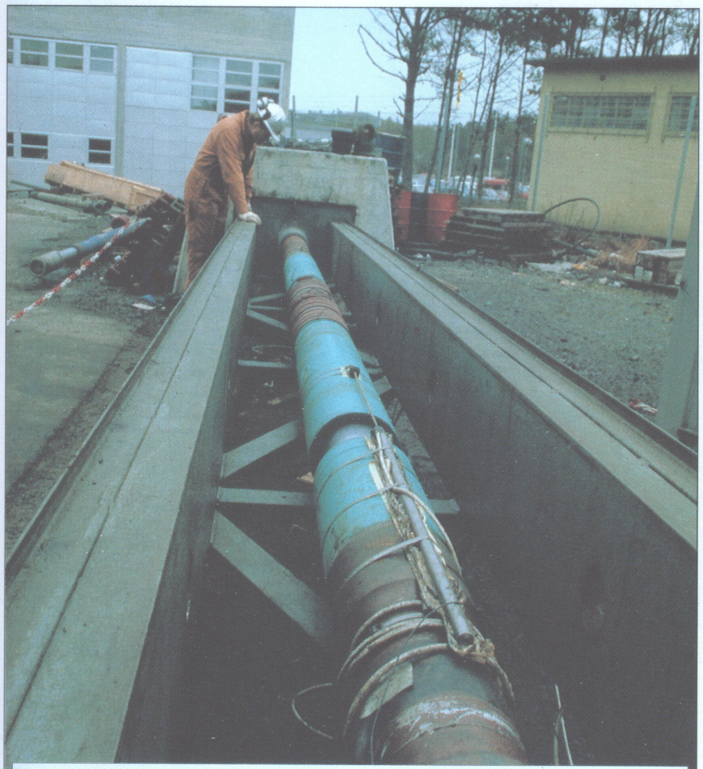


Figure 2
View of the test rig.
In the foreground is the linear-displacement transducer that measures the jar extension; the anchor foundation is visible in the background.

two of the 10 accelerators tested were judged to be worth recommending. The rig time that would be spent trying to free a stuck drillstring using a jar such as that depicted in Figure 3a is entirely wasted, and the chances of freeing the string later with a fishing string would be reduced. (Shell Operating Companies can obtain advice on which tool(s) to select from SIPM or KSEPL.)

Follow-up

Manufacturers of jars and accelerators have been informed of their own tools' test results, and some have reacted with design changes. The modified tools will be tested in the autumn of 1990.

Regardless of what tool is used, Shell's jarring operations can be designed using the computer program JARTROP. This program is based on theoretical jar properties and not on the properties as measured in the test programme. The jarring forces calculated by JARTROP can therefore be safely assumed to be overestimated and conservative. For that reason, a total drillstring fracture due to jarring is unlikely if the operation is designed with the program. This conclusion has been confirmed by a check of the Nederlandse Aardolie Maatschappij's drilling data base that covered a one-year period. An update of JARTROP, incorporating the measured jar properties, is currently under development.

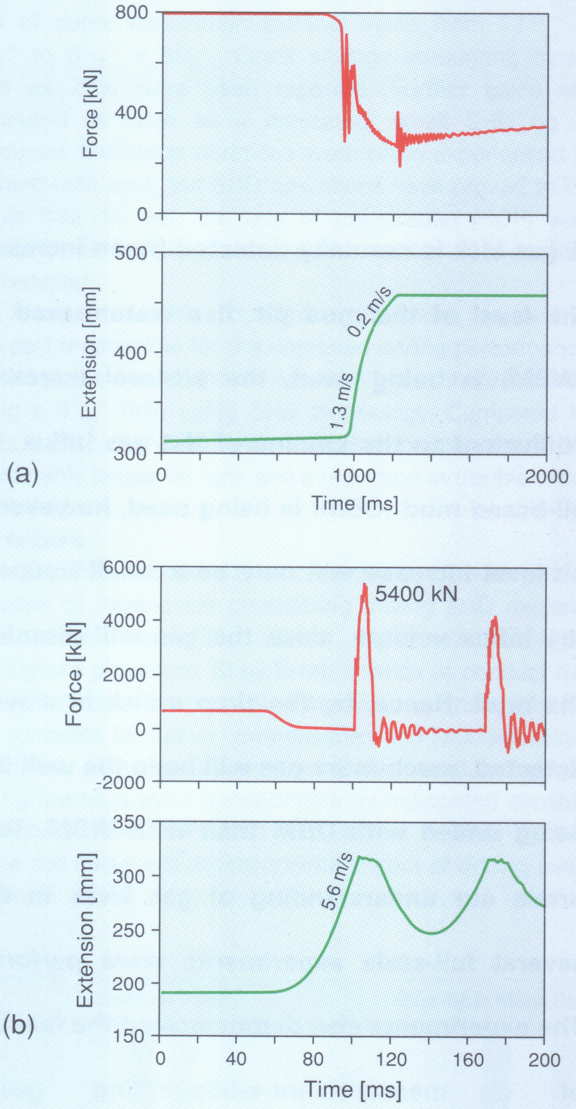


Figure 3
Test results for a bad (*a*) and a good (*b*) jar.
In both cases, the upper graph shows the force at the stuck point, and the lower graph the jar extension; all graphs are plotted against time. Note that the two time scales and the two force scales differ by an order of magnitude. The high internal friction in the bad jar prevents the jar extension from speeding up, resulting in a negligible impact (750 kN at a pulling force of 800 kN). Even with a much higher elasticity in the drillstring (as would be the case for a very deep well), the maximum extension speed would be 1.3 m/s, which is still much below that of a good jar. In a good jar the speed of extension increases steadily after release of the trigger mechanism, to a value of 5.6 m/s. The resulting impact force at the stuck point is 5400 kN at a pulling force of 710 kN.

Gas kicks in oil-based mud

A gas kick is normally detected by an increase in the level of the mud pit. If a water-based mud (WBM) is being used, the pit-level increase is equivalent to the volume of the gas influx. If an oil-based mud (OBM) is being used, however, the pit-level increase will only be a small fraction of the influx volume, since the gas will dissolve in the mud. Hence, by the time a kick in a well is detected, much more gas will be in the well if it is being drilled with OBM than with WBM. To improve our understanding of gas kicks in OBM, several full-scale experiments were performed. The experiments also demonstrated the feasibility of a measurement-while-drilling gas-kick detection system.

Gas kicks in water-based and oil-based muds

Measured values of the bottomhole pressure (BHP) and the mud outflow rate for a gas kick in a water-based mud (WBM) and in an oil-based mud (OBM) are presented in Figure 1. Operating conditions and the injection rate of gas were the same for both kicks. The kick in the WBM develops according to expectations: gas enters the wellbore as free bubbles, which then travel upwards faster than the mud, expanding and coalescing as they go. Accurate observation of the mud-pit level or of the difference between mud inflow and outflow would ensure that such a kick would be detected at an early stage.

The kick in the OBM, however, behaved unexpectedly. Preliminary calculations had indicated that the mud would be supersaturated with gas at bottomhole conditions, and therefore the gas would come out of solution immediately after injection. Thereafter, it was thought, the free gas would behave like it does in a WBM. Yet there was virtually no measurable change in outflow

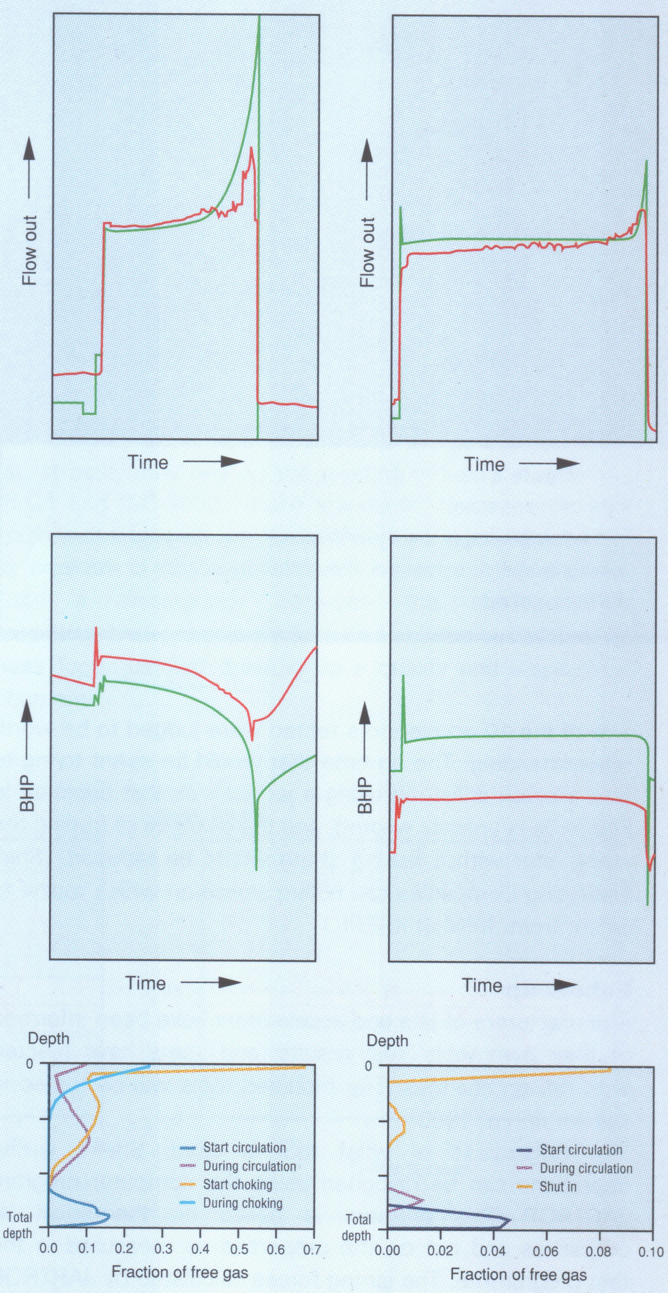


Figure 1

Development of a gas kick in water-based mud *(left)* and in oil-based mud *(right)* up to the point at which the well is shut in. Measured *(red)* and calculated *(green)* mud outflows and bottomhole pressures (BHP) are given for the two types of mud. The calculated distribution of free gas in the well at various times *(bottom)* is also shown for both cases.

and BHP—the indicators of free gas during the development of the gas kick in the OBM.

The gas apparently had come out of solution in the OBM, but dissolved again after it rose into mud that was undersaturated with gas. This process of gas going into and coming out of solution seems to have taken place repeatedly as the fluid was circulated. Only at the very last moment, just before the gas-saturated mud reached the surface, did the gas finally come out of solution to provide a surface indication. Such behaviour, of course, makes it difficult to detect a kick before it turns into a blowout. On the other hand, such behaviour also means that a kick in OBM produces low pressures at the casing shoe, a vulnerable point in the well.

To check this reasoning both experiments were simulated using a computer model. The simulation results, also given in Figure 1, describe the general features of gas kicks in both types of mud.

Gas-kick detection

As part of this set of experiments, a kick-detection method patented by Teleco was tested. The method is based on the effect that gas bubbles have on the pressure pulses generated downhole by a measurement-while-drilling (MWD) system (Figure 2). Every time a MWD pulser produces a normal, positive pulse that travels up inside the drillpipe, it also generates a corresponding negative pulse that travels in the opposite direction, through the bit and into the annulus between the drillpipe and the borehole wall or casing. The shape of this secondary pulse, which can be measured just above the blowout preventer, is affected by gas bubbles in the annulus. Hence, by comparing the shapes of the positive and negative pulses, the influx of gas into the annulus can be detected. Although the Teleco system was put through only a simple test, the results were promising.

KSEPL also carried out several experiments in the training well of the Nederlandse Aardolie Maatschappij. The objective of the experiments was to study gas-kick development and detection in a slim-hole well, since early kick detection with a conventional system is difficult in such wells. In this connection, encouraging results were obtained from a preliminary test of a gas-kick detection system that relies on flow meters to measure the difference between mud inflow and outflow.

Future work

Gas kicks in high-pressure, high-temperature wells and during slim-hole drilling will be further studied with the aid of the computer model. The model will also be used to evaluate the existing design criteria related to well control.

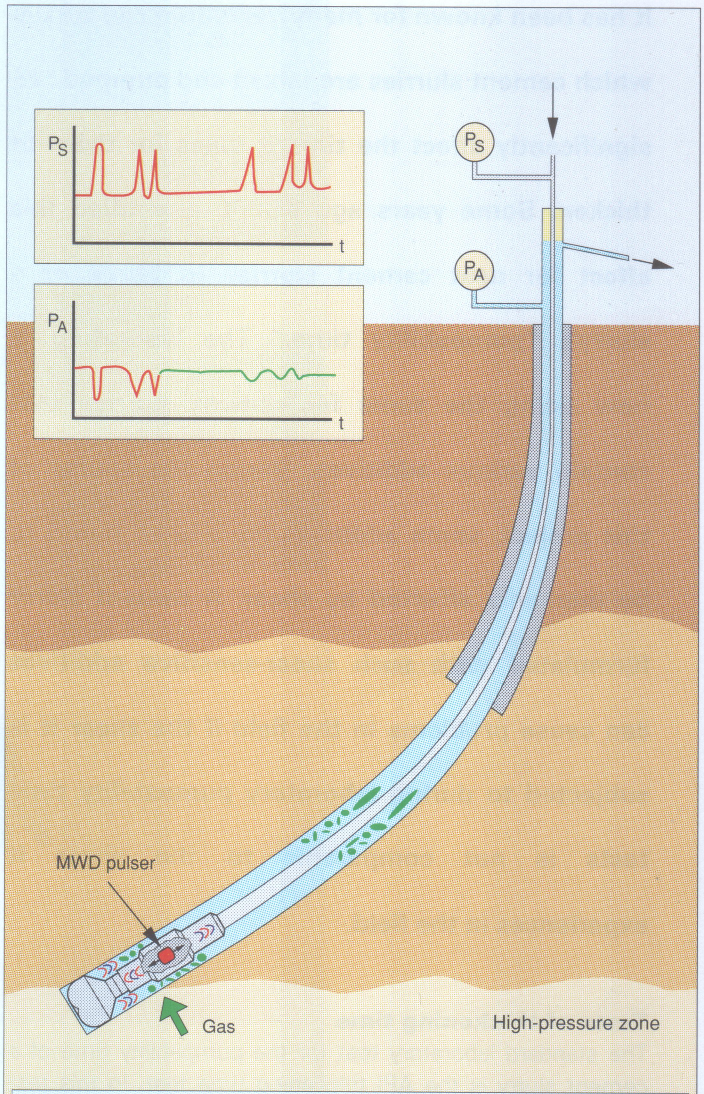


Figure 2

GAS-KICK DETECTION METHOD UTILISING A MEASUREMENT-WHILE-DRILLING (MWD) PULSER.

Every time the MWD pulser generates a normal, positive pulse that travels up inside the drillstring, it also generates a corresponding negative pulse that travels in the opposite direction, through the drill bit and into the annulus between the drillstring and the borehole wall. Because gas bubbles affect a pulse's amplitude and travel time, comparing the timing and shape of the pulses in drillpipe (PS) and annulus (PA), reveals when gas has entered the annulus.

The influence of shear on the setting time of cement

It has been known for many years that the way in which cement slurries are mixed and pumped can significantly affect the time it takes for them to thicken. Some years ago KSEPL quantified this effect for neat cement slurries in terms of a slurry's "pumpability time." The laboratory is now doing the same for cement slurries that contain various additives. During the course of this project, some additives have been found to be markedly affected by shear. A cement slurry formulated with such shear-sensitive additives can cause problems in the field if the shear it is subjected to during laboratory pumpability time tests is not comparable to the shear it experiences in the field.

Tests of thickening time

The standard laboratory test for the pumpability time of a cement slurry is the API thickening time test. In this test the consistency of a cement slurry is measured at downhole temperature and pressure by means of a rotating paddle. The rotating paddle, however, subjects the slurry to a shear that is typically much higher than the shear it would undergo when pumped in the field. Figure 1 compares the shear rate applied during field operations to that applied in the API test.

Shear's effect

Shearing a slurry affects the processes that take place at the surfaces of cement particles during the cement's hydration reactions, influencing the setting of the cement. In general, shearing a neat slurry tends to shorten its pumpability time and final setting time. The effect of shearing is even more pronounced in slurries containing common cement additives, such as retarders, fluid-loss controllers and dispersants. These agents often contain organic molecules that are adsorbed onto the aluminate and calcium hydroxide nucleation centres and thereby inhibit the reactions of the setting cement. Shearing can influence the adsorption process and hence the relative effectiveness of the organic additives.

Figure 2 shows that the influence of shear on the initial setting time (pumpability time) of a slurry containing varying amounts of retarder is comparable to that of pressure. From extensive laboratory testing of this kind, it has become clear that the setting times of slurries that contain a retarder are very sensitive to the amount of applied shear. Slurries containing a fluid-loss additive or a dispersant are mildly to moderately susceptible to shear, whereas slurries that contain a latex-type additive are virtually unaffected by shear.

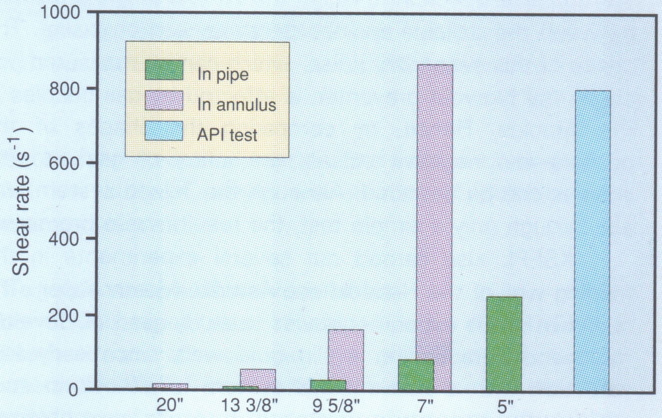


Figure 1

TYPICAL RATES OF SHEAR TO WHICH A CEMENT SLURRY IS SUBJECTED DURING ACTUAL PUMPING IN THE FIELD AND DURING THE API THICKENING TIME TEST.

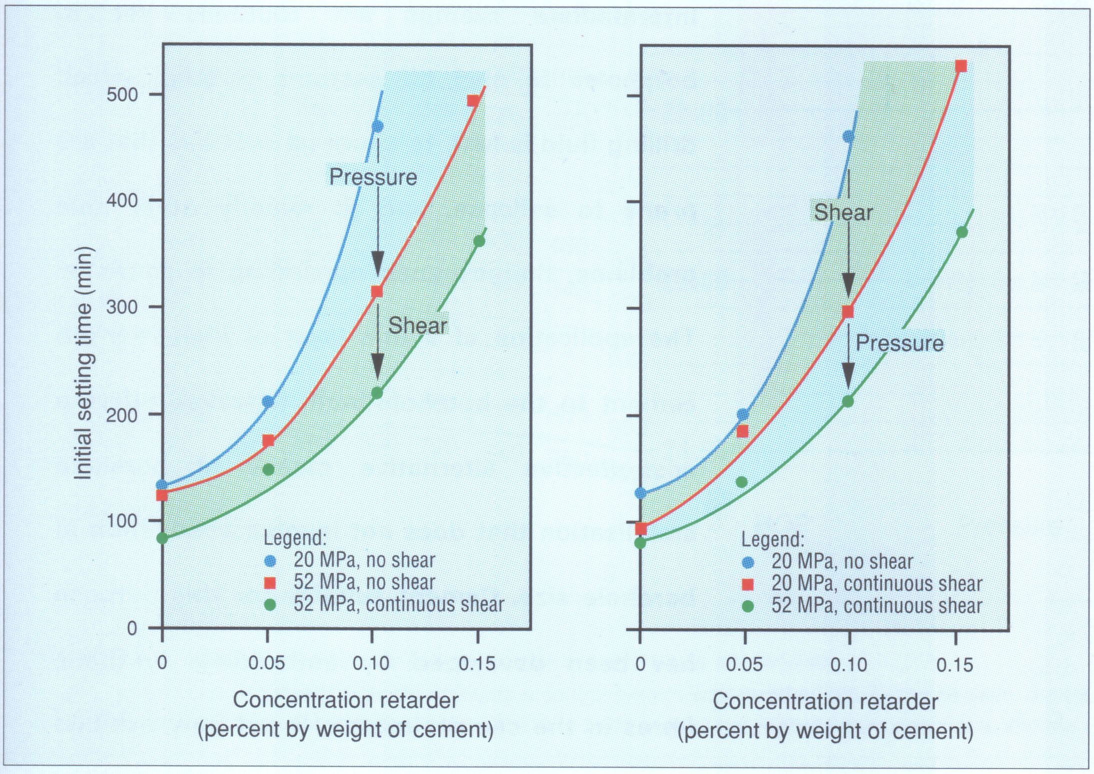


Figure 2

The influence of pressure *(blue)* and shear *(green)* on the setting time of cement as a function of retarder concentration.

What does it mean for Operating Companies?

The implication of these observations for Shell Operating Companies is that slurries formulated on the basis of the laboratory API thickening time test will have longer-than-expected setting times under low-shear conditions (e.g., when low pump rates or large casing sizes are used) but may set prematurely under high-shear conditions (e.g., if the slurry is sheared for a time at the surface before it is pumped, or if high pump rates or small casing sizes are used). The experimental results also imply that uncertainties over pumpability time simulations can be minimised if less shear-sensitive cement additives are employed.

High-strength cement as a substitute for intermediate casing

Intermediate casings are routinely set in boreholes to seal off sections through which drilling fluid is lost, to shore up sections that are prone to collapse, and to remedy other hole problems, thereby enabling drilling to continue. The application of a thin layer of high-strength cement to the borehole wall, however, offers a cost-effective alternative means of borehole stabilisation that does not involve a reduction in borehole size. Cement suitable for this purpose has been developed by embedding synthetic fibres in the cement matrix. It not only exhibits the necessary high strength but also has better wear characteristics than steel casing.

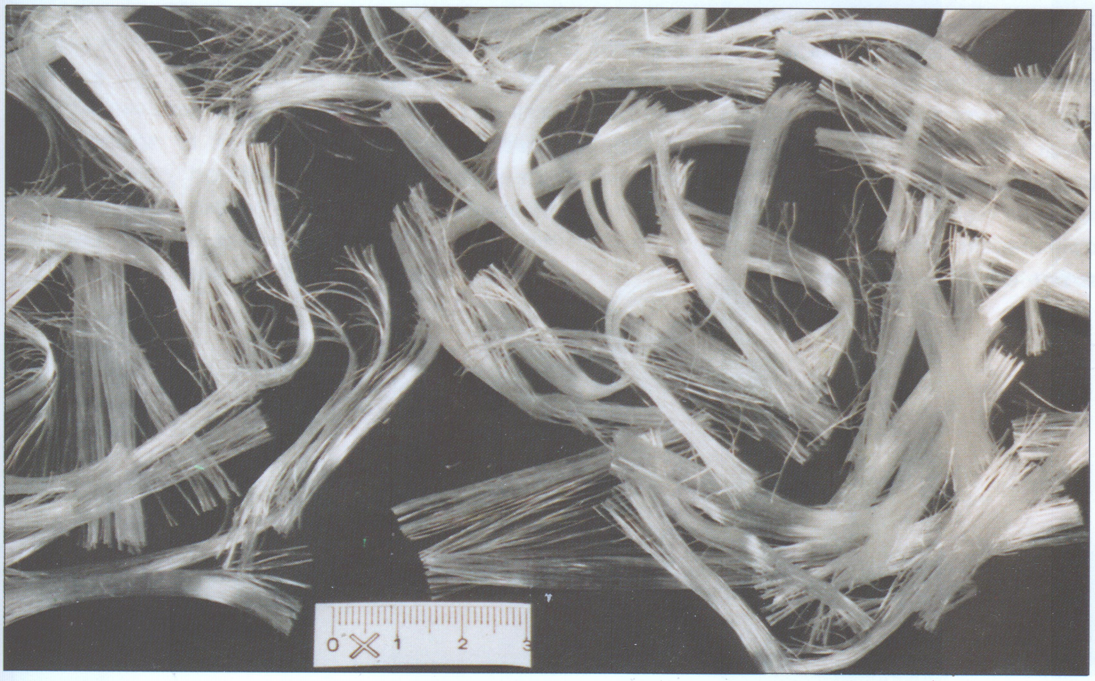


Figure 1
SYNTHETIC FIBRES USED TO REINFORCE CEMENT.

Adding fibres to strengthen cement

Ordinary cement has good compressive strength but, being essentially a brittle material, it also has poor tensile strength. The ductility of cement can be improved, however, if synthetic fibres (see Figure 1) are embedded in the cement matrix, thereby yielding a composite material with superior strength characteristics. Figure 2 presents the stress-strain curves of neat cement and fibre-reinforced cement under flexural loading. The figure shows that, after failure of the cement matrix, the fibres in the composite take over the load, endowing it with a far greater ultimate flexural strength than that of neat cement.

High-strength cement as borehole liner

Because such a high-strength cement can withstand both compressive and tensile loading, it can be applied to remedy such drilling problems as differential sticking, sloughing shales, salt dissolution and lost circulation. Figure 3 illustrates the way this would be done. Essentially, the cement would serve as a kind of temporary casing. The resistance of the cement composite to wear and impact from the combined action of circulating mud and a rotating drillstring has been tested and shown to be sufficient for maintaining the integrity of the borehole under ordinary pressure conditions. In fact, it takes longer for the drillstring to wear through the high-strength cement lining than it does through common types of steel casing.

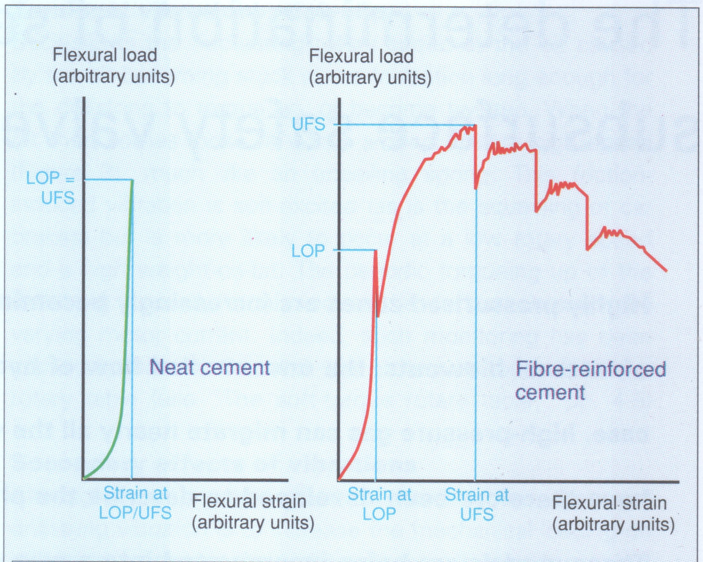


Figure 2

STRESS-STRAIN CURVES OF NEAT AND FIBRE-REINFORCED CEMENTS UNDER FLEXURAL LOADING.

The area under the stress-strain curve is a measure of the toughness of the material tested. (LOP=limit of proportionality; UFS=ultimate flexural strength.)

Sealing off trouble zones by lining the zone with fibre-reinforced cement makes it possible to drill longer sections of hole at one go, thus enabling tighter casing schemes to be used and reducing the amount of drilled solids and casing costs.

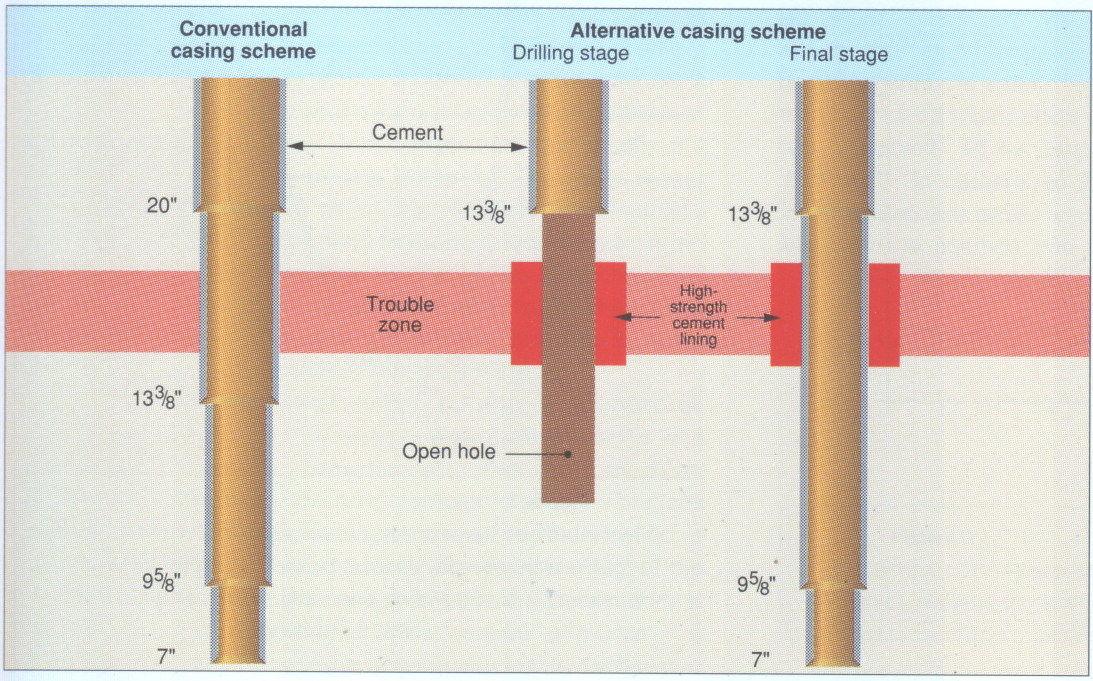


Figure 3

SCHEMATIC REPRESENTATION OF A HIGH-STRENGTH CEMENT LINING THAT HAS BEEN APPLIED TO SEAL OFF A TROUBLE ZONE.

The determination of setting depths for subsurface safety valves

Highly pressurised zones are increasingly becoming targets for drilling. This trend could increase the risk of internal blowouts: the uncontrolled flow of hydrocarbons through the drilled formation. In the worst case, high-pressure gas can migrate nearly all the way to the surface, where it can create a crater. Models have therefore been developed to describe the physical processes that are involved in such a situation. These models are being incorporated into a new computer program that will enable a better evaluation of the risks associated with internal blowouts. In particular, the program will provide an assessment of the setting depth of subsurface safety valves that is more realistic than that calculated according to existing models.

Internal blowouts

In an internal blowout high-pressure gas from one zone generally leaks into the wellbore, from which it invades another drilled formation. The processes that may then take place in the invaded formation are depicted in Figure 1. To begin with, the gas will fill the pore space of permeable layers. The charging with gas may in turn induce a collapse of the rock matrix, which may hamper drilling of relief wells. The gas could build up pressure in the permeable formation to such an extent that the overlying, sealing layer fractures. The gas may then flow upwards to charge the next permeable layer, and so on until the gas reaches the surface. Alternatively, the high-pressure gas can travel upwards through existing faults that it has opened. If the high-pressure gas meets an unconsolidated layer of soil near the surface, a crater might be formed near the surface. The soil in this crater will be "fluidised," and all wells within the crater will be sheared off (Figure 2). Moreover, the fluidised soil may cause the drilling rig or platform to become unstable and perhaps even to sink (Figure 3).

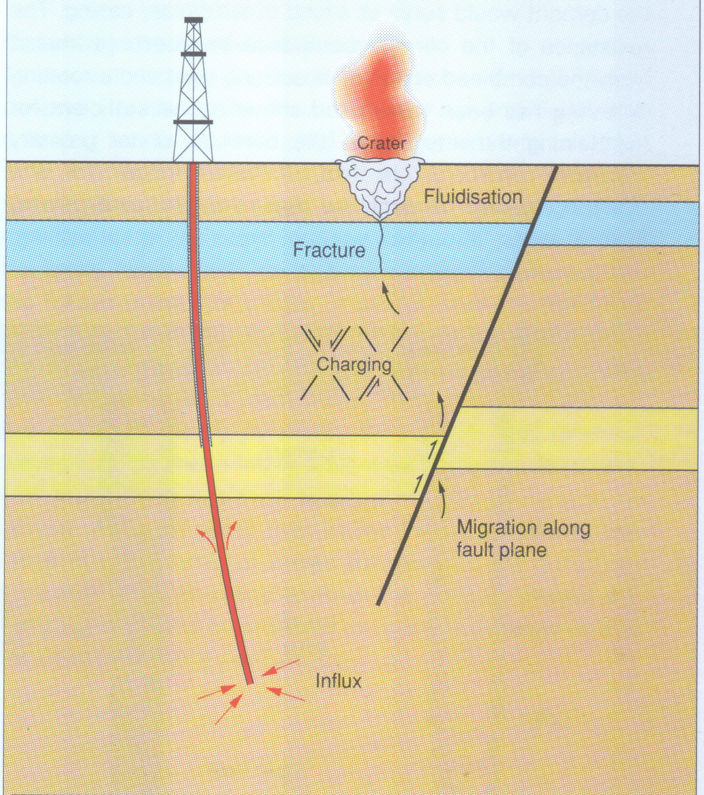


Figure 1

PROCESSES THAT MAY TAKE PLACE AS A RESULT OF AN INTERNAL BLOWOUT. High-pressure gas may open up faults, charge permeable formations, fracture sealing layers and finally create a crater containing "fluidised" soil at the surface.

A program to assess the risk

To minimise the potential for catastrophe associated with the formation of a crater, subsurface safety valves should be located below the depth where craters are likely to form in the event of an internal blowout. Existing models to determine this depth often yield unrealistic results. A more accurate determination of this depth is an important aspect of the study of internal blowouts underway at KSEPL.

To help get a grasp on the problem, a new model of the processes associated with internal blowouts—including fracturing and fluidisation—is being constructed. Because the new model is intended to yield more realistic predictions, a large effort is being made to ensure that the rock parameters and lithology is properly assessed from the limited data available. These data normally comprise logs (although they are often not available for shallow depths), drilling records, cuttings, foundation reports and general geological descriptions. The expertise required to make such an assessment will be collected from the different disciplines involved through structured knowledge engineering. At the same time, a number of actual cases have also been analysed to obtain field input at an early stage.

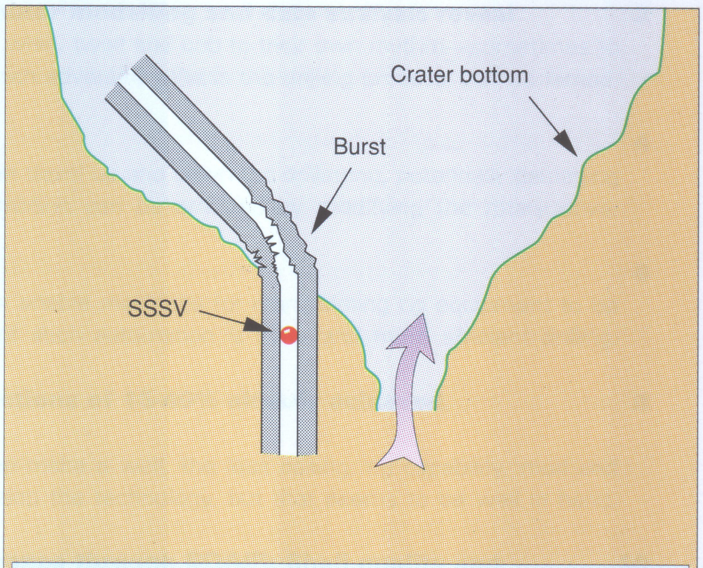


Figure 2

WELL DAMAGE DUE TO CRATERING.
A subsurface safety valve (SSSV) should be set deep enough to prevent further gas flow in the event of cratering.

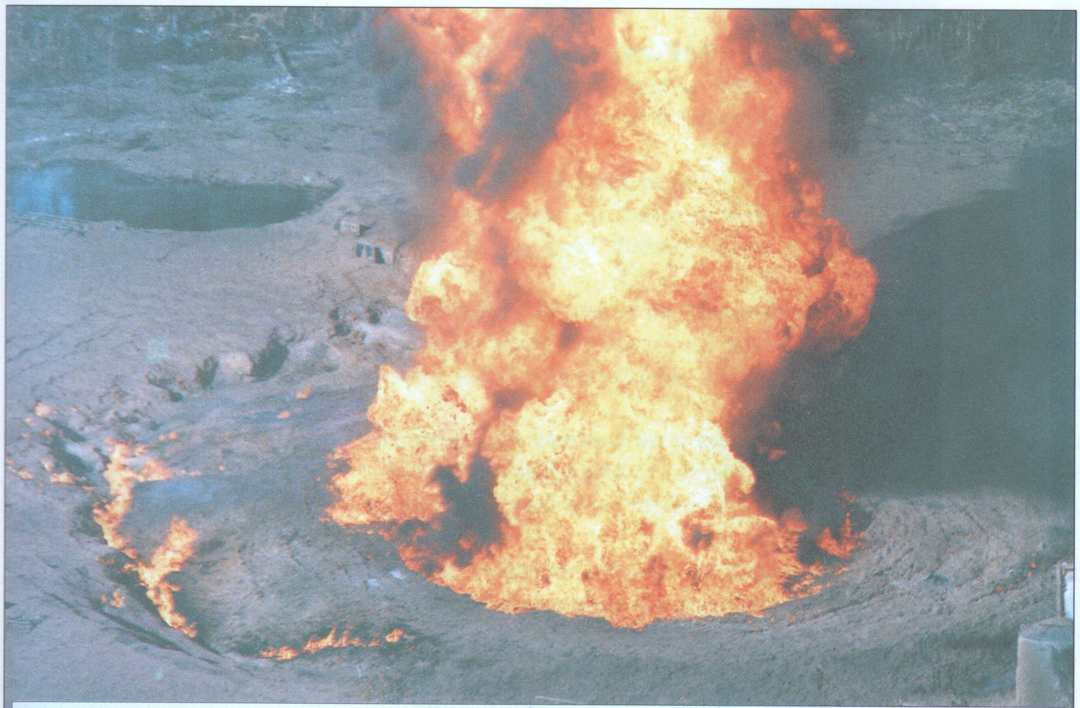


Figure 3

EQUIPMENT SINKING INTO THE FLUIDISED SOIL OF A CRATER CAUSED BY AN INTERNAL BLOWOUT.

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